NiSource Corporate Services

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May 31, 2005

BY OVERNIGHT DELIVERY AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's responses to the following information requests of the Department:

DTE-1-9	DTE-1-21	DTE-1-26	DTE-3-6	DTE-3-7	DTE-3-8
DTE-3-10	DTE-3-15	DTE-3-16	DTE-3-28	DTE-3-29	DTE-3-30
DTE-3-31	DTE-4-18	DTE-4-21	DTE-4-24	DTE-4-38	DTE-4-40
DTE-4-41	DTE-4-45	DTE-4-46	DTE-4-47	DTE-4-48	DTE-4-55
DTE-4-56					

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French

cc: Caroline O'Brien Bulger, Esq., Hearing Officer (1 copy)
A. John Sullivan, DTE (7 copies)
Andreas Thanos, Ass't Director, Gas Division
Alexander Cochis, Assistant Attorney General (4 copies)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: May 31, 2005

Responsible: Steven A. Barkauskas, Vice President
Joseph A. Ferro, Manager, Regulatory Policy

DTE 1-9 Refer to Exh. BSG/SAB-1, at 46. Will the pension and PBOP expenses incurred during the test year be recovered in base rates or through the proposed reconciling adjustment? If recovery of these expenses is intended through the reconciling adjustment, provide the period of time over which these expenses are sought to be recovered.

Response: As indicated in the testimony of Joseph A. Ferro in Exhibit BSG/JAF-3, the recovery of the annual test year level of pension and PBOP expenses will be moved from base rates and recovered through a reconciling adjustment mechanism as a component of the Company's Local Distribution Adjustment Clause ('LDAC"). On a going forward basis, any amount of pension and PBOP expense greater than the 2004 test year level would be amortized over a three-year period, and thus, one-third of the amortized amount will be reflected in the subsequent three years' Pension and PBOP Expense Factor ("PEF"). The annual recovery period, as set out in Section 5.05 of the LDAC, proposed M.D.T.E. 37, Page 14 of 47, is November 1 through October 31.

As supported in the testimony of John E. Skirtich, Exhibit BSG/JES-1, the test year annual pension and PBOP expense is $5,630,282.

As an example, if the Company were to experience for the twelve month period ending 12/31/2005 annual pension and PBOP expenses of $6.5 million, then the Company would seek to recover $5.9 million through the PEF beginning November 1, 2006:

$5.6M + ($6.5M-5.6M) / 3 or $5.6M+0.30M = $5.9M.

The additional $300,000, plus carrying charges, would also be included in the PEF for the next two years, effective Nov. 1, 2007 and 2008.

Any difference between the actual recovery of pension and PBOP expenses and the intended recovery amount, which would be caused by the variance between actual and forecast firm sales and transportation volumes, would be recovered or returned through the Reconciliation Adjustment (RA_{PE}).

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Date: May 31, 2005

Responsible: Stephen H. Bryant, President

DTE 1-21 Refer to Exh. BSG/SHB-1, at 50. Has the $10,095,382 early termination payment associated with the Metscan meter reading devices been made? If so, provide the date or dates on which payment was made. If payment has not yet been made, provide the anticipated date when payment will be tendered?

Response: Pursuant to the terms of the lease agreements, a termination payment is due to Banc America. Bay State is currently engaged in discussions with Banc America (successor to Fleet Capital Leasing) to determine the lowest cost alternative available to Bay State to fulfill that remaining financial obligations under the Metscan leases. The Company expects to conclude those discussions early while this proceeding is pending and will then update and supplement this response with the results of those discussions, which will include the final amount due and payable and relevant date(s).

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Date: May 31, 2005

Responsible: John E. Skirtich, Consultant (Revenue Requirements)

DTE 1-26 Refer to Exh. BSG/JES-1, Sch. JES-17, at 9. Please provide the basis for the inclusion of carrying costs from the in-service date of the plant additions associated with the steel infrastructure replacement program as part of the Steel Infrastructure Replacement Base Rate Adjustment, in light of the Department's long-standing practice requiring utilities under its jurisdiction to stop accruing Allowance for Funds Used During Construction when plant is placed in service, as opposed to when the plant is included in rate base in a rate case.

Response: Allowance for Funds Used During Construction/Interest During Construction ("AFUDC/IDC") recognizes the carrying costs incurred by the company during the construction period. The carrying costs during the construction period are capitalized for future recovery. Capitalization of the carrying costs is discontinued once the property is placed in to service. Conceptually, revenue will commence once the property is placed in service allowing the company to recover its costs including any capital costs.

Bay State's Steel Infrastructure Replacement ("SIR") program is a commitment by Bay State to replace a major portion of its system which is "non-revenue" producing. The "in-service" date for these expenditures is not synonymous with revenue generation. Some of the projects will be placed into service close to 18 months (April through October) before revenue is received through the SIR base rate adjustment.

As indicated in Exhibit BSG/JES-1, Schedule JES-17, at 9, Bay State will incur carrying costs of $2.6 million annually that recovery will not occur under the Department's current requirement. The $2.6 million of carrying costs is a major drain on Bay State's earnings, and unless the Department provides for recovery as proposed by Bay State or as an alternative continue recognizing AFUDC until the effective date of the new rates, Bay State will have little opportunity to achieve its allowed rate of return as granted in this proceeding.

COMMONWEALTH OF MASSACHUSETTS
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RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRD SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-6 Refer to Exh. BSG/DGC-1, at 16. Please provide any studies, reports and memoranda relied upon by the Company to support its conclusion that Bay State's recent corrosion leak rate per year is three times the leak rate of 17 years ago.

Response: Please see Attachment DTE-3-6 for two graphs that illustrate: (1) 20 years worth of Company-wide system corrosion <u>leak rates</u> on unprotected steel mains compared to total miles of unprotected steel mains; and (2) 20 years worth of Company-wide system corrosion <u>leak rates per mile</u> on unprotected steel mains compared to total miles of unprotected steel mains.[1]

For example, the data on Page 1 of Attachment DTE-3-6 demonstrates that Bay State had 250 corrosion leaks in 1987 compared to 771 corrosion leaks in 2003, which constitutes a 3-fold increase in leaks during that period. This increase in the absolute number of leaks occurred while at the same time the total amount of unprotected steel mains declined through replacement by approximately 50%, from a total amount of 1254 miles of unprotected main in 1987 to 615 miles in 2003.

Further, the data on Page 2 of Attachment DTE-3-6 demonstrates that on a leaks-per-mile basis the corrosion leak rate in the Bay State system has escalated by a factor of 6, going from 0.2 leaks per mile in 1987 to 1.25 leaks per mile in 2003.

In sum, both the absolute number of leaks and the leaks per mile data demonstrate that the number of leaks on Bay State's remaining unprotected steel system is accelerating, and such data fully support the Company's proposal to implement a systematic and comprehensive Steel Infrastructure Replacement program.

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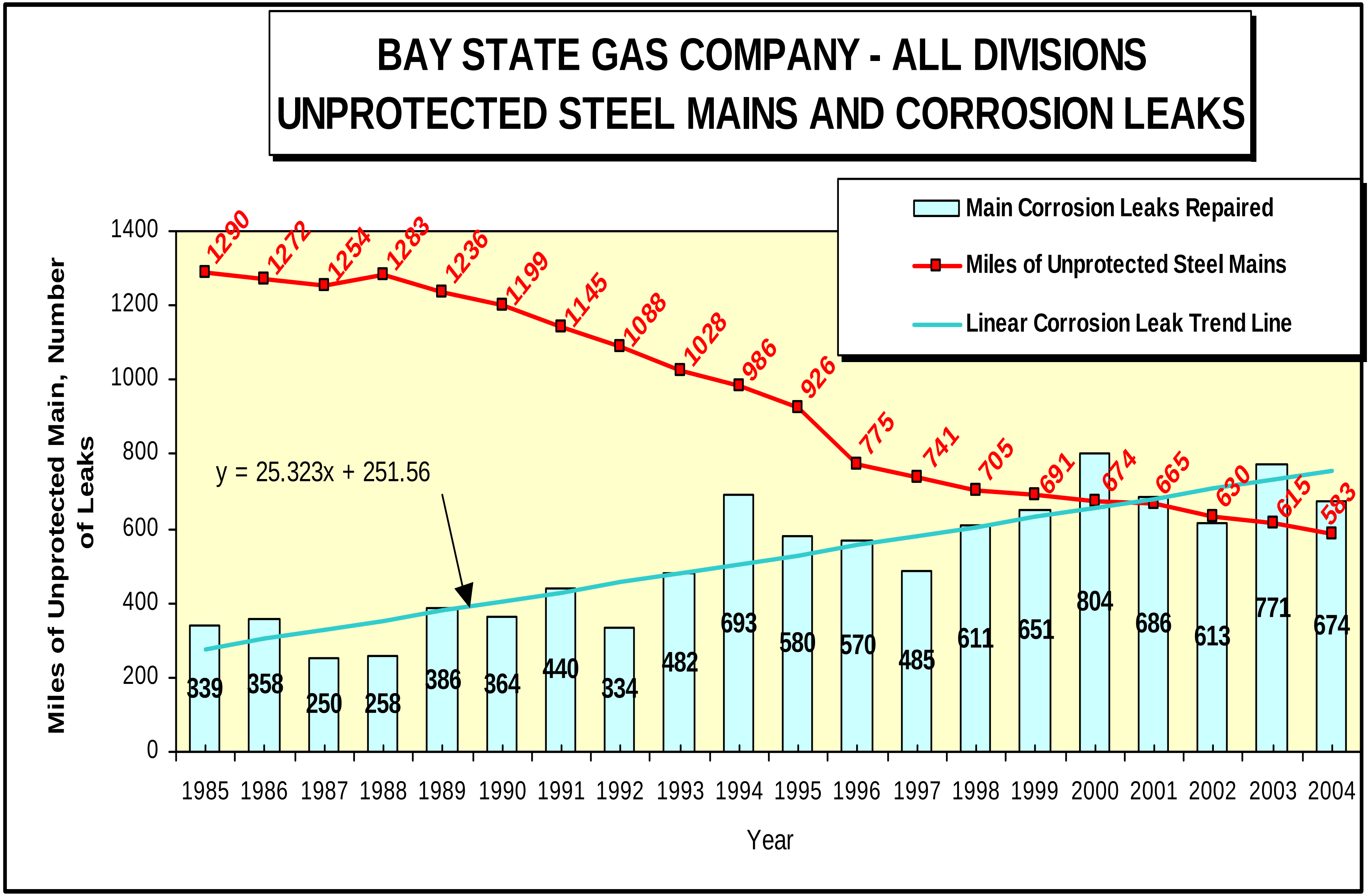
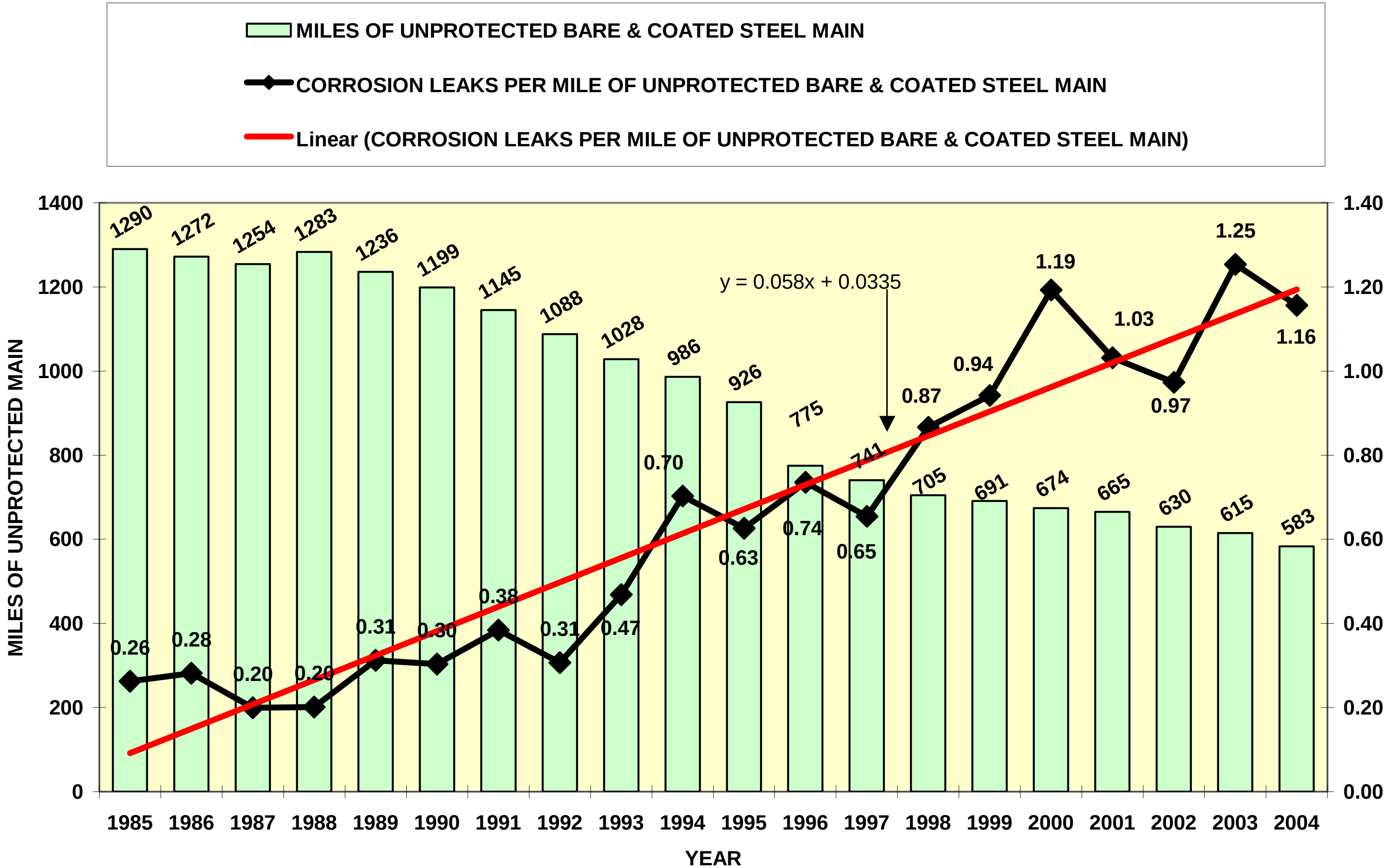
[1] The Work Order Management System ("WOMS") is unable to differentiate between corrosion leaks occurring on cathodically protected bare steel and cathodically protected coated steel. Therefore, Bay State's operational management judgment presumes that all corrosion leaks are associated with unprotected steel mains (i.e., unprotected bare steel and unprotected coated steel).

Bay State Gas Company



BAY STATE GAS - ALL DIVISIONS
MILES OF UNPROTECTED BARE & COATED STEEL MAIN AND CORROSION LEAK REPAIR RATE PER MILE



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Responsible: Danny G. Cote, General Manager

DTE-3-7 Refer to Exh. BSG/DGC-1, at 19. Please explain why higher operating pressures cause corrosion leaks more quickly than would lower operating pressures. Provide any supporting studies for this statement.

Response: Higher operating pressures do not accelerate corrosion rates. Higher operating pressures do, however, increase the “hoop stress” on pipe walls. If a pipe has suffered wall thickness loss due to corrosion, the pipe has become weaker at that location. Since there is less pipe material to resist the increased stress imposed by the higher operating pressure, the likelihood of a leak increases at that point of corrosion.

“Hoop stress” is defined by the following equation:

$$\text{Hoop Stress} = \frac{\text{Operating Pressure} \times \text{Pipe Diameter}}{2 \times \text{Pipe Wall Thickness}}$$

Therefore, as the pipe wall thickness decreases, the Hoop Stress increases.

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Responsible: Danny G. Cote, General Manager

DTE-3-8 Refer to Exh. BSG/DGC-1, at 7. Please provide with supporting calculations an estimate of the percentage of Bay State's system that operates at pressure of 100 pounds per square inch gauge or greater. Provide these percentage estimates separately for the Brockton, Lawrence and Springfield service areas.

Response: Please see Table DTE-3-8.

TABLE DTE-3-8

DIVISION	% PIPE GREATER THAN 99 PSIG*
Brockton:	90%
Lawrence:	35%
Springfield:	3%

* The percentages in Table DTE-3-8 by dividing the total number of miles of mains in each Division that operate at pressures greater than 99 psig by the total number of miles of main in each Division.

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Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-10 Refer to Exh. BSG/DGC-1, at 10-14. Please provide for the years 1985 through 2004 the following:

1) the lengths of mains by type of pipe (e.g., cast iron, wrought iron, bare steel, coated steel, cathodically protected steel, plastic) in the Brockton, Lawrence, and Springfield service areas, as well as the Company-wide totals;
2) the lengths and costs of non-discretionary replacement mains installed by type of pipe in the Brockton, Lawrence, and Springfield service areas, as well as the Company-wide totals;
3) the lengths and costs of discretionary mains installed by type of pipe in the Brockton, Lawrence, and Springfield service areas, as well as the Company-wide totals.

Response: Please see Attachment DTE-3-10(a), Attachment DTE-3-10(b), Attachment DTE-3-10(c) and Attachment DTE-3-10(d) for the requested information.

Please note that the data sources for Attachments DTE-3-10(a) – (d) are the RSPA F7100.1-1 Distribution System Annual Reports and associated worksheets, called Part B-1. Historically Bay State has reported its three Division service territory data in the aggregate. Instructions for completing the F7100.1-1 reports require the operator to report all figures as whole numbers, and not use decimals or fractional numbers. In addition, decimals and fractions are required to be rounded up or down to the nearest mile. Consequently, occasionally there is one-mile disparity between Division data and consolidated (Bay State-total) data for some pipe type categories.

In compiling the data requested in order to respond to DTE 3-10(1), Bay State discovered that for calendar years 1985, 1986 & 1987, there were disparities between the individual Division data and consolidated Bay State data with regard to the reported miles of unprotected bare steel and unprotected coated steel. Bay State's review of the source data resulted in a determination that the disparity resulted from numbers reported for the Lawrence division in 1985, 1986 & 1987. In addition, for calendar year 1993, Bay State accounted for 1722 miles of cathodically protected coated steel main; the correct number was 1704 miles, based upon data from individual Division worksheets.

Bay State Gas | Historical Mains Data | 1985-2004

all bsg

Year	Unprotected Bare Steel	Unprotected Coated Steel	Cathodically Protected Bare Steel	Cathodically Protected Coated Steel	Plastic	Cast & Wrought Iron	Total Miles of Main
1985	636	654	0	1488	64	1005	3847
1986	623	649	0	1500	120	1003	3895
1987	615	639	0	1509	144	1000	3907
1988	721	562	0	1477	277	997	4034
1989	700	536	0	1524	345	992	4097
1990	688	511	0	1558	402	988	4147
1991	677	468	0	1600	467	979	4191
1992	648	440	0	1650	542	976	4256
1993	638	390	0	1722	613	958	4321
1994	624	362	0	1738	696	943	4363
1995	607	319	0	1781	758	936	4401
1996	593	182	0	1925	821	921	4442
1997	580	161	0	1950	886	910	4487
1998	562	143	0	1976	952	897	4530
1999	551	139	0	1985	1012	889	4576
2000	543	133	0	1994	1063	881	4614
2001	534	131	0	1995	1110	874	4644
2002	527	112	0	2012	1140	869	4660
2003	506	109	0	2024	1177	867	4683
2004	477	106	0	2034	1255	846	4718

Brockton Division — Historical Mains Data — 1985-2004

BR mains (data source are DOT worksheets)

Year	Unprotected Bare Steel	Unprotected Coated Steel	Cathodically Protected Bare Steel	Cathodically Protected Coated Steel	Plastic	Cast & Wrought Iron	Total Miles of Main
1985	480	331	0	980	26	296	2113
1986	470	328	0	990	61	296	2145
1987	463	327	0	995	101	295	2181
1988	453	324	0	1008	145	294	2224
1989	447	303	0	1038	191	293	2272
1990	437	277	0	1066	221	292	2293
1991	429	236	0	1107	259	289	2320
1992	419	201	0	1145	301	287	2353
1993	412	154	0	1193	341	283	2383
1994	404	130	0	1220	385	281	2420
1995	389	86	0	1267	424	279	2445
1996	378	70	0	1287	462	273	2470
1997	370	73	0	1288	500	271	2502
1998	357	80	0	1285	540	265	2527
1999	346	79	0	1290	572	261	2548
2000	338	76	0	1293	604	259	2570
2001	331	74	0	1294	636	256	2591
2002	327	72	0	1294	653	254	2600
2003	320	70	0	1296	674	254	2614
2004	305	63	0	1306	722	256	2652

Lawrence Division — Historical Mains Data — 1985-2004

LA mains (data source are DOT worksheets)

Year	Unprotected Bare Steel	Unprotected Coated Steel	Cathodically Protected Bare Steel	Cathodically Protected Coated Steel	Plastic	Cast & Wrought Iron	Total Miles of Main
1985	86	9	0	139	22	229	485
1986	83	9	0	141	28	229	490
1987	74	9	0	146	36	228	493
1988	119	9	0	101	46	228	503
1989	106	4	0	118	50	226	504
1990	106	5	0	124	55	225	515
1991	106	3	0	126	57	225	517
1992	89	10	0	136	62	225	522
1993	89	8	0	142	70	222	531
1994	88	4	0	150	77	219	538
1995	89	5	0	146	84	217	541
1996	88	10	0	141	93	213	545
1997	87	5	0	146	101	211	550
1998	85	9	0	145	106	208	553
1999	86	7	0	149	115	206	563
2000	85	3	0	154	121	205	568
2001	84	3	0	154	124	204	569
2002	82	3	0	154	130	203	572
2003	72	3	0	163	135	203	576
2004	72	3	0	163	147	194	579

Springfield Division | Historical Mains Data | 1985-2004

SP mains (data source are DOT worksheets)

Year	Unprotected Bare Steel	Unprotected Coated Steel	Cathodically Protected Bare Steel	Cathodically Protected Coated Steel	Plastic	Cast & Wrought Iron	Total Miles of Main
1985	156	229	0	369	16	480	1250
1986	153	229	0	369	31	478	1260
1987	152	229	0	368	55	477	1281
1988	149	229	0	368	86	475	1307
1989	147	229	0	368	104	473	1321
1990	145	229	0	368	126	471	1339
1991	142	229	0	368	151	465	1355
1992	139	229	0	368	179	461	1376
1993	137	228	0	369	202	453	1389
1994	132	228	0	370	234	443	1407
1995	129	228	0	369	250	440	1416
1996	127	102	0	497	266	435	1427
1997	123	83	0	515	285	428	1434
1998	120	54	0	546	306	424	1450
1999	120	53	0	546	325	422	1466
2000	119	53	0	546	340	418	1476
2001	118	53	0	546	353	416	1486
2002	118	37	0	563	359	412	1489
2003	114	36	0	565	368	410	1493
2004	100	40	0	565	386	396	1487

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DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

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D. T. E. 05-27

Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-15 For years 2000 through 2004, please provide schedules with supporting data and calculations comparing the average size of mains that were removed with the average size of mains installed for the Brockton, Lawrence, Springfield service areas as well as Company-wide. Describe the Company's method used as well as any assumptions relied upon.

Response: The typical size of mains removed and the typical size of mains installed for the years 2000 through 2004 for main replacement work are shown below:

	Typical Size Removed	Typical Size Installed
Brockton	1½" - 2"	2" & 4"
Lawrence	4"	4" & 6"
Springfield	4"	4" & 6"
All BSG	1½" - 4"	2" - 6"

For replaced mains, the Company installs a minimum of 2" diameter pipe on systems operating at pressures greater than or equal to ½ psig, and a minimum of 4" diameter pipe on systems operating at pressures less than ½ psig (low pressure). The Company also uses distribution system modeling software called Advantica (Stoner) SynerGEE to select main replacement pipe sizes. This software package is very common in the industry and it simulates system performance, including gas pressures and flows, during design days and allows the Company's system engineers to plan for expected growth over the estimated life of the replaced main. Growth and system planning is considered at the time of all main replacements due to the low incremental cost associated with permitting additional capacity by installing larger pipe diameters. Pipe upsizing, when projected growth warrants it, adds a relatively small incremental amount of cost to a project's total cost. According to its management judgment, Bay State considers upsizing where indicated to be a reasonable and prudent operating and system planning practice.

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Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-16 Refer to Exh. BSG/DGC-1, at 25. Please list and explain the reasons why the Company would decide to use cathodically protected steel mains versus plastic mains in its steel infrastructure replacement program.

Response: There are several operational bases for the installation of pipe type, whether it be cathodically protected coated steel ("CPCS") or High Density Plastic ("HDPE" or "plastic pipe").

1) CPCS would be installed on all above-ground situations (e.g. bridges);
2) CPCS would be installed in gas distributions systems that have or could have in the future a maximum allowable operating pressure (MAOP) of <u>more than</u> 99 psig. Currently, industry standards recommend and Federal code only allows the use of HDPE for MAOP <u>up to</u> 99psig;
3) CPCS would be installed in situations where the gas main would be exposed to high temperatures, such as pipes in close proximity to steam lines; and
4) CPCS would be installed when the replacement situation called for a pipe size larger than 8 inch in diameter. Bay State normally installs 2, 4, 6 and 8 inch diameter plastic pipe in the majority of its installations. However, in the event that a larger pipe size were required, CPCS would likely be the appropriate choice.

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Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-28 Refer to Exh. BSG/DGC-1, at 18-19. Please provide any studies, reports and memoranda used by the Company as a basis for using the area-based mains replacement strategy. List all other approaches considered and state the reasons why they were not selected.

Response: Bay State established the operational paradigm of the SIR based on its management and operational expertise and judgment that is derived from years of direct experience managing a natural gas distribution system.

Part of the reason "area-based mains replacement" is preferred as a basis for the SIR is because the Company consistently has seen lower costs per job if it bundles work together in the same geographic area. This practice allows contractors to reduce travel time for their equipment and labor and the set-up time for equipment and labor, and therefore the overall charges billed to Bay State. Establishing worksites in more condensed geographic areas also enhances the amount of Bay State supervision over contractor activities, because internal supervisory personnel are able more readily to move from one job to the next.

Bay State considered one alternative to the SIR: to continue operating under a performance replacement, compliance replacement and opportunistic approach, each described in AG-2-12, which was a strategy that focused more on replacing the worst individual segments of unprotected steel with little regard to a more systematic approach. However, this old approach was not considered, because it no longer seems as prudent or practical as it once did given the current circumstanced faced by Bay State.

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Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-29 Refer to Exh. BSG/DGC-1, at 18-19, and 24. Please provide a copy of any plan developed by the Company showing the geographic locations and time-lines for phasing in the replacement of mains under its steel infrastructure replacement program.

Response: As shown on Exh. BSG/DGC-5, the total miles of unprotected steel mains as well as the total number of steel services, tie-overs, meters and regulators that are to be replaced over the course of a 10 to 15 year period based on a review of DOT pipe inventory data. The "phase-in" is rolling and continuous. As geographic sections are replaced, cut-offs and tie overs occur, plant is retired and new mains and services come on-line for service. The determination of the time horizon for the program was made by dividing the total expected Steel Infrastructure Replacement ("SIR") program costs in current dollars by a reasonable annual level of expenditures (e.g., between $20 – $25 Million), and taking into consideration management's judgment relative to the accelerating leak rates, customer bill impacts, and availability of internal and external resources.

Bay State has no map of its distribution service areas, as is suggested by the question, that reflects a specific, long-term list of targeted geographic locations in the SIR ranked by date to be accomplished from 2004 through the end of the program in 2014 or later. This is not the type of management task that Bay State would undertake for a large operations project because guidance in construction activity is provided on a locational (or municipal) and continuing operational analysis and generally on a 6-12-18 month guidance, not looking out up to 15 years. The effort to create the map the AG envisions by the question would not lead to any actionable information.

Bay State's construction plan must be and is flexible and responsive to all data inputs and information regarding the system and external influence as such information is gathered. Moreover, the plan must reflect the fact that Bay State is not able to conduct underground construction year-round. Bay

State's construction season lasts from approximately April through October, depending on weather. Given the limited time period for physical replacement each season, Bay State must be productive and efficient with its resources.

What Bay State does do to establish its plan for geographic replacement of unprotected steel infrastructure is to consider each year as part of its construction season planning process the following: (1) areas with high corrosion leakage rates, (2) areas where there is planned municipal work, and (3) any emergency situations. This information yields actionable information about areas to be targeted during the construction season.

Further, as stated in the Cote Testimony, the initial strategy is to emphasize the replacement of unprotected steel in its Brockton service territory during the early years of the SIR program while maintaining the flexibility to target other areas as opportunities and needs arise. This is because of both the large percentage of bare steel infrastructure relative to the Lawrence and Springfield Divisions as well as the particular operating characteristics of this part of the Company's system.

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Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-30 Refer to Exh. BSG/DGC-1, at 24. Please provide for the years 2005 through 2014 the following:

1) any budget forecast for the Company's steel infrastructure replacement program; and
2) a list of target municipalities where the Company plans to replace mains indicating the Company service area(s) for each municipality identified.

Response: As noted in the Company's response to DTE-3-29, Bay State is forecasting to spend between $20-$25 Million on its total annual Steel Infrastructure Replacement ("SIR") program.

1) As noted in the Company's response to DTE-3-29, it is very difficult to predict with certainty exactly which municipalities will be targeted in the SIR program between 2005 and 2014. However, as identified on Page 24 of Exh. BSG/DGC-1, the Company has targeted the following municipalities in 2005 to be included as part of the SIR program:

   <u>Springfield Division:</u> Agawam, Chicopee, Easthampton, East Longmeadow, Granby, Longmeadow, Ludlow, Northampton, South Hadley, Springfield, and West Springfield.

   <u>Brockton Division:</u> Attleboro, Hanover, Pembroke, Avon, Hanson, Plympton, Bellingham, Holbrook, Randolph, Berkley, Lakeville, Raynham, Bridgewater, Mansfield, Scituate, Brockton, Marshfield, Seekonk, Canton, Medfield, Sharon, Dighton, Medway, Stoughton, Duxbury, Millis, Taunton, East Bridgewater, Norfolk, Walpole, Easton, Norton, West Bridgewater, Foxboro, Norwell, Wrentham, and Franklin.

   <u>Lawrence Division:</u> Andover, Lawrence, Methuen, and North Andover.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRD SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: May 31, 2005

Responsible: Danny G. Cote, General Manager

DTE-3-31 Refer to Exh. BSG/DGC-9, at 22-23. Please describe with supporting documentation and work papers how the Company determined the $20 million annual incremental expenditures over the 10- to 15-year period for its steel infrastructure replacement program.

Response: As further described in the Company's response to DTE-3-29, Bay State's current estimate of total Steel Infrastructure Replacement ("SIR") program costs was supplied in Exh. BSG/DGC-5. This estimate was derived from a review of DOT pipe inventory data including the quantity of bare steel mains, the number of bare steel and plastic services (which is currently on file with the commission), the mix of inside and outside risers and meters in it's system, and current construction costs.

The Company then determined the 10 to 15 year SIR program time horizon by dividing the total SIR program costs in current dollars by a reasonable annual level of expenditures (e.g., between $20 – $25 Million). This annual level of SIR expenditures was based on the judgment of the Company's operational and senior management to be reasonable and appropriate considering the accelerating leak rates, customer bill impacts, availability of internal resources and ability to locate, competitively bid, evaluate and contract external resources.
In sum, Bay State's management concluded that this timeline would provide an expedited unprotected steel replacement schedule while still providing efficient program management without a substantial increase in Bay State staff or undue pressure on third party vendors.

Further, 2005 is a year in which Bay State will continue to develop an even more sophisticated understanding of the operational costs, construction management issues and operational challenges presented by the accelerated SIR program, and then to use this knowledge to adjust the program going forward as necessary.

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-18 Referring to the econometric cost analysis, please:
(a) indicate which cost share equation will be dropped from the system;
(b) specify the number of parameters to be estimated;
(c) identify the exogenous and endogenous variables of the system.

Response: (a) The cost share equation for non-labor O&M cost was dropped from the system.

(b) We estimate a total of 16 parameters.

(c) There are two equations; the endogenous variable in the O&M cost equation is O&M costs for gas distribution; the endogenous variable in the labor cost share equation is the share of labor in gas distribution O&M cost. The exogenous variables for the O&M cost equation are:

- a constant term
- the price of labor (wl)
- the total number of customers (y1)
- total gas deliveries (y2)
- a second order term for wl (i.e. wl squared)
- a second order term for y1
- a second order term for y2
- an interaction term between wl and y1
- an interaction term between wl and y2
- an interaction term between y1 and y2
- the percent of non-cast iron and bare steel pipes in distribution miles
- the number of electric customers served
- a northeast dummy variable
- total miles of distribution main
- a customer growth variable
- a time trend variable.

The exogenous variables in the labor cost share equation are:

- a constant term
- y1

- y2
- wl

As discussed in BSG/LRK-2, the labor cost share equation was obtained by differentiating the O&M cost equation with respect to the labor price (wl). A necessary implication is "that the parameters in this (cost share) equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself" (BSG/LRK-2 at 24). Therefore the 16 coefficients estimated in the O&M cost equation reflect the total number of parameters estimated. In the cost share equation, parameter estimates for y1, y2, and wl appear from the O&M cost equation, and the constant is equal to the average share of labor in O&M cost in our sample.

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Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-21 Refer to Exh. BSG/LRK-2. Please indicate whether the cost trend analysis and the econometric cost study for Bay State distinguished between distribution and non-distribution labor and O&M expenses. If not, explain why not? Also, explain what effect, if any, the failure to distinguish between distribution and non-distribution labor O&M expenses would have on the results of the cost trend analysis and the econometric cost analysis for Bay State, on the conclusions regarding the Company's cost performance during the study period.

Response: Both empirical analyses only included distribution O&M expenses.

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-24 Refer to Exh. BSG/LRK-2. Please discuss the research design and the sample selection process used for the econometric cost study for Bay State. State whether the sample used for the econometric cost study is a representative sample of gas utilities in the United States. If not, explain why, and discuss how the selection of a non-representative sample could affect the results of the econometric cost study?

Response: The sample was the same as that used for Boston Gas in DTE 03-40, except that Bay State itself was added to the sample. The sample in the Bay State econometric study was designed to be as comparable as possible with the Boston Gas precedent.

This sample of US gas distributors is also representative of conditions in the industry. The 43 sampled distributors serve 53% of US end-users. Gas distributors are also sampled from throughout the country, although the Northeast is somewhat over-represented. Sampled distributors range in size from about 67,000 to over 5,000,000 customers and face a wide range of labor input prices, climate conditions, customer bases and other operating conditions. It should also be noted that the Department did not object to the US gas distribution sample in DTE 03-40 and found that the sample for PEG's productivity work "balanced the objectives of comprehensiveness, heterogeneity, and cost" (DTE 03-40 at 475).

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-38 Refer to Exh. BSG/LRK-1, at 7-8 and 11-12. Reconcile the Company's position that because Bay State "operated for more than five years under an alternative to traditional cost of service regulation that created strong performance incentives, the Company's "situation is analogous to Boston Gas Company's at the expiration of its initial PBR plan" with the Company's argument that a five-year term for the proposed PBR plan is appropriate because it is "consistent with Department precedents for gas distribution companies that are proposing rate indexing PBR plans for the first time."

Response: These statements are logically consistent and do not need to be reconciled. Like Boston Gas at the time DTE 03-40 was issued, Bay State has been subject to a multi-year rate plan that was designed to create stronger performance incentives. Both Bay State and Boston Gas proposed new PBR plans when their initial plans expired.

However, Bay State is proposing a rate indexing PBR plan for the first time. The Department has, to date, approved four index-based PBR plans for gas distributors in the state. The initial plan for Boston Gas (DPU 96-50) approved a five year term; the initial plan for Berkshire Gas (DTE 01-56) began with a 31 month rate freeze followed by an 89 month term for price indexing; the updated plan for Boston Gas (DTE 03-40) has a ten year term; and the initial plan for Blackstone Gas (DTE 04-79) has a five year term. In only one of these cases (DTE 03-40) has the Department approved a ten-year indexing term, and this was for a distributor that was updating an index-based PBR plan. In two instances (DPU 96-50 and DTE 04-79) the Department approved a five-year term for distributors that were implementing index-based PBR for the first time. The Berkshire plan was for a combined rate-freeze and rate-indexing PBR, and the terms of the rate freeze and rate indexing periods summed to 10 years.

Bay State has been subject to a rate freeze for five years, and it now proposes to be subject to rate indexing PBR for five years. This is consistent with the Berkshire precedent where the terms of the rate freeze and rate indexing PBR plans summed to ten years. It is also consistent with DPU 96-50 and DTE 04-79 where the Department approved a five-year term for distributors that were implementing index-based PBR for the first time.

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-40 Refer to Exh. BSG/LRK-1, at 7-8 and 11-12. Discuss the advantages and disadvantages of a five-year PBR plan versus a ten-year PBR plan for a regulated gas utility like Bay State in terms of the following:
(i) creating an environment that allows for medium and long-term efficiency planning and business decision-making;
(ii) providing a stronger incentive for companies to achieve efficiency gains and significant cost savings through innovation, deployment of productivity-enhancing technology, and other measures;
(iii) reducing the regulatory and administrative burdens of implementation; and
(iv) exposing the Company to market and/or other risks.

Response: All of the statements in (i) - (iv) above are more likely under a ten-year PBR plan than a five-year plan. That is, compared with a five-year PBR, a ten-year PBR plan term generally creates stronger performance incentives, is more conducive to longer-term planning, reduces regulatory burdens *and* exposes the Company to greater risk. The theoretical merits of a five-year versus a ten-year PBR term therefore depend on the tradeoff between creating strong incentives and minimizing risk or, equivalently, the weights that regulators place on promoting incentives and reducing risk. It should be noted, however, that the Company decided to propose a five-year PBR plan mainly because it believed a five-year term was more consistent with Department precedents, particularly since the most recently approved PBR plan for a gas distributor (Blackstone Gas) had a five-year term.

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Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-41 Refer to Exh. BSG/LRK-1, at 7-8 and 17-18. Please discuss how the Z-factor and earnings sharing mechanism ("ESM") proposed by the Company mitigate any market and/or other risks that shareholders and ratepayers may face if the Department approved a ten-year PBR plan for the Company.

Response: The Z-factor and earnings sharing mechanism (ESM) will not mitigate the risks associated with a ten-year PBR plan vis-à-vis a five-year plan since these same plan provisions are also available under a five year plan. In other words, any ability of these provisions to mitigate risk would be equally present in a five-year PBR plan and a ten-year PBR plan. However, there is always a possibility that some events (*e.g.* higher interest rates) will not be "covered" by the Z-factor or ESM, and the probability of such events occurring can only increase as the length of the plan term increases.

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Date: May 31, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-4-45 Refer to Exh. BSG/LRK-1, at 7-8. Please state the start and end dates of the Company's PBR plan. When will the last rate adjustment under the proposed PBR plan take effect?

Response: The Company's proposed 5-year PBR rate plan pertains to the operating years of calendar year 2005 through 2009. The rates in effect for the first year of the plan will be established by the Department in this instant proceeding, D.T.E. 05-27. The first rate adjustment in accordance with the PBR plan pertains to year 2 and will become effective on November 1, 2006. The last rate adjustment is associated with year 5 of the plan and will become effective on November 1, 2009.

Please see the Company's proposed Annual Base Rate Adjustment Mechanism tariff, M.D.T.E. No. 63, filed under the testimony of Joseph A. Ferro as Schedule JAF-2-8. Page 2 of M.D.T.E. No. 63, Section 2.1 -- Term of PBR Base Rate Adjustment Mechanism, establishes the term of five years through October 31, 2010, the end of the last rate adjustment period of November 1, 2009 through October 31, 2010.

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Date: May 31, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-4-46 Refer to Exh. BSG/LRK-1, at 7-8. Please explain how rates will be set under the proposed PBR plan.

Response: Please refer to the testimony of Joseph A. Ferro, Exhibit BSG/JAF-2 and the associated Schedule JAF-2-8, which is the proposed Annual Base Rate Adjustment Mechanism ("ABRAM"), M.D.T.E. No. 63. Section 7 of this tariff sets out how rates will be set, including Definitions, Formula and description of the Annual Rate Adjustment mechanism. Also refer to Schedule JAF-2-9, which is an illustrative calculation of the ABRAM.

Prior to the derivation of adjusted base rates in accordance with the PBR plan, annual revenues subject to the PBR adjustment and an overall revenue adjustment target is established. The annual revenues are based on the previous calendar year, by multiplying weather normalized distribution volumes, or billing determinants, by the current base rates of each rate Schedule as of December 31, excluding the component of base rates associated with the Steel Infrastructure Replacement ("SIR) program. The revenue adjustment target is derived by applying the GDPPI, less the X factor established by the Department in this instant proceeding, D.T.E. 05-27, plus a percentage reflecting any applicable Exogenous costs and Earning Sharing associated with the previous calendar year in accordance with the PBR plan.

Each element of the base rates for each Rate Schedule is adjusted by the GDPPI inflation adjustment, less the X factor, plus a percentage reflecting any applicable Exogenous costs and Earning Sharing. The maximum adjustment to any base rate element is the GDPPI inflation adjustment. At that point the portion of annual base rate adjustment associated with the PBR plan is complete.

The two additional steps in the base rate adjustment set out in the ABRAM are not associated with the PBR plan. First, an adjustment is made to base rates associated with the recognition of the reduction in distribution volumes in connection with the annual therm savings resulting from the Company's installation of energy efficiency ("EE") measures in that previous calendar year. This is not an adjustment according to the PBR plan, but rather in accordance with the Company's proposed ABRAM. Nonetheless, the resulting adjusted PBR base rates are adjusted by a percentage equal to the test year billing determinants (BD) divided by BD minus the EE therm savings, minus 1. This approach allows for an adjustment to base rates, consistent with the PBR and other ABRAM base rate adjustments, rather than to revenues through the LDAC. The rate adjustment calculation of using a percentage equal to [BD / (BD-EE therms) – 1] is equivalent to adjusting revenues (EE therms x an incremental base rate) dividing by test year billing determinants.

The final adjustment involves adding the base rate adjustment per therm associated with the SIR program. This rate adjustment is derived by allocating the SIR revenue requirement to every element of base rates based on the percentage of revenues currently being derived from base rates. The resulting allocation of revenues is then divided by the previous calendar year billing determinants to derive the SIR base rate adjustment by rate element of each Rate Schedule (monthly charge for Customer Charge and unit charge per them for volumetric rates).

In sum, (1) current base rates are adjusted for the percentage adjustment in accordance with the PBR plan; (2) the resulting rates are adjusted by a percentage associated with EE therm savings; and (3) the final adjustment is the SIR base rate adjustment in the form of a charge per month (for the monthly Customer Charge) and unit charge per therm for the volumetric rates.

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Date: May 31, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-4-47 Refer to Exh. BSG/LRK-1, at 7-8. Is the Company proposing to continue the PBR Plan on a year-to-year basis after the initial five-year term? Explain.

Response: Yes. The Company is proposing to continue the PBR Plan on a year-to-year basis after the initial five-year term until such time it believes it can no longer achieve the intended efficiencies of the Plan that allow for optimal customer service, operational flexibility and reasonable Company earnings.

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Date: May 31, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-4-48 Refer to Exh. BSG/LRK-1, at 7-8. If Bay State is proposing to continue the PBR Plan on a year-to-year basis after the initial five-year term, will the Company notify the Department each year of its intention to continue with the PBR plan for another year? If the answer is in the affirmative, indicate the date on which the Company intends to notify the Department.

Response: The Company plans to continue with the PBR Plan after the initial five-year term and, rather than notifying the Department each year of its intention of continuing the Plan, it is proposing to notify the Department of <u>discontinuing</u> the Plan by virtue of filing with the Department the Company's intent to file for a general rate increase. Such notification would come approximately thirty days prior to the Company's general rate case filing.

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-55 Refer to Exh. LRK-2, at 18. Please:
(a) discuss the factors that determine "the number of gas distribution customers added [to an LDC's distribution system] in the last 10 years";
(b) discuss how the age of an LDC's distribution system is related to each of the above factors;
(c) discuss the ways in which acquisitions and mergers affect the age of an LDC's distribution plant as measured by the "system age" proxy;
(d) discuss how the inclusion of a poor or inappropriate proxy variable in an econometric cost model can affect the results of the study.

Response:

(a) The most important factor that determines the number of gas distribution customers added to an LDC distribution system in the last 10 years is population/customer growth in the LDC's service territory.

(b) The average age of a gas distribution system is clearly related to the pattern of new customer additions. Gas distribution systems are built, and extended over time, in order to connect new customers. This implies, for example, that the gas distribution system for Boston Gas is "older" than the system for Northwest Natural Gas primarily because natural gas service was extended to a much larger share of Boston Gas's current customer base at an earlier time. This also implies that a *smaller* share of Boston Gas's customer base was added in the last 10 years than is the case for Northwest Natural Gas.

(c) Mergers and acquisitions should not affect the age of a given distributor's age of plant. I believe our system age proxy satisfies this condition since we have controlled, to the greatest practical extent, for mergers and acquisitions over the sample period.

(d) Any "proxy" variable is a surrogate for another variable. Researchers use proxies when it is not possible or cost effective to obtain accurate data on a given variable of interest. Naturally, for the proxy to produce reliable econometric estimates, it should have a strong relationship the variable of interest. I believe this is the case with our system age proxy.

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Date: May 31, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-56 Refer to Exh. LRK-2, at 20. Refer to Exh. LRK-2 at 20. If the Gas Distribution O & M number in Row 1 is divided by the Number of Customers number in Row 2, a per customer O & M figure of .14 emerges for the U.S. sample and .25 emerges for Bay State, indicating that Bay State's per customer O & M is close to double that of the U.S. sample. Does this difference in sample characteristics between Bay State and the national sample have any influence on the predictive model derived to predict Bay State's O & M costs? If so, how would the model be effected?

Response: No. The national sample is highly diverse. All else equal, sample heterogeneity leads to more reliable estimates of the cost function parameters. Exhibit BSG/LRK-2 at 13 contains a discussion of the factors that affect the sample prediction error for the econometric model.